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Techno-economic comparison of energy storage systems for island autonomous electrical networks

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Abstract

The oil-dependent electricity generation situation met in the Aegean Archipelago Islands is in great deal determined by increased rates of fuel consumption and analogous electricity production costs, this being also the case for other island autonomous electrical networks worldwide. Meanwhile, the contribution of renewable energy sources (RES) to the constant increase recorded in both the Aegean islands' annual electricity generation and the corresponding peak load demand is very limited. To compensate the unfavorable situation encountered, the implementation of energy storage systems (ESS) that can both utilize the excess/rejected energy produced from RES plants and improve the operation of existing thermal power units is recommended. In the present study, a techno-economic comparison of various RES-ESS configurations supported by the supplementary or back-up use of existing thermal units is undertaken. From the results obtained, the shift of direction from the existing oil-dependent status to a RES-based alternative in collaboration with certain storage technologies entails – apart from the clear environmental benefits – financial advantages as well.

Keywords: Techno-economic comparison; Electricity generation; Energy storage; Autonomous electrical network; Renewable energy sources

Contents

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Nomenclature

c_e	specific energy storage system's capacity cost (€/kWh)
c_f	specific energy cost of fuel used (€/kWh)
c_p	specific energy storage system's power cost (€/kW)
c_0	present electricity generation cost of the energy storage system (€/kWh)
c_1	specific input energy cost (€/kWh)
C_{ss}	total cost of the energy storage system (in present values)
CF	capacity factor of the under study electrical network
CF_{ss}	capacity factor of the energy storage system
d_0	energy autonomy period of the energy storage system (h)
DOD_L	maximum permitted depth of discharge of the energy storage system
E_{dir}	energy demand covered directly by the existing power stations (kWh)
E_h	average hourly load of the electrical network under study per annum (kW)
E_{ss}	energy storage capacity of the energy storage system (kWh)
E_{stor}	energy demand covered directly by the energy storage system (kWh)
E_{tot}	annual energy demand of the local electricity network (kWh)
EC	cost of input energy utilized to charge the energy storage system (€)
FC_{ss}	fixed M&O cost of the energy storage system (€)
g_k	mean annual change of cost for major parts to be replaced
i	capital cost of the local market
IC_{ss}	initial investment cost of the energy storage system (€)
k-th	major components of the energy storage system
k_0	major parts to be replaced during the system's service period
l_k	times of replacement for major parts being replaced (integer number)
m	fraction of annual M&O cost to the total initial investment
n	years of operation for the proposed configuration (years)
n_k	lifetime of energy storage system's major parts to be replaced
n_{ss}	service period of the energy storage system (years)
N_{in}	maximum input power of the energy storage system (kW)
N_p	annual peak load demand of the local electricity network (kW)
N_{ss}	nominal output power of the energy storage system (kW)
N_0	rated power of the existing power stations (kW)
r_k	replacement cost coefficient for major parts to be replaced
SF	safety factor for the under study electrical network
vc_{ss}	non-dimensional variable maintenance cost of the energy storage system
VC_{ss}	variable maintenance cost of the energy storage system (€)
Δt_{ch}	charge time for the energy storage system (h)
x_1	mean annual escalation rate of the input energy price
x_2	mean annual M&O cost inflation rate
x_3	mean annual escalation rate of fuel input price
x_4	mean annual escalation rate of electricity price
Y_n	residual value of the energy storage system (€)

Greek letters

γ	ratio of State subsidy to the total investment cost
ε	energy demand ratio covered directly by the energy storage system
ζ	peak load demand ratio covered by the energy storage system
η_p	power efficiency of the energy storage system
η_{ss}	energy transformation efficiency of the energy storage system (round-trip)
ρ_k	mean annual change of technological improvement for major components
$\tilde{\upsilon}_n$	non-dimensional residual value of the energy storage system (in present values)

1. Introduction

The several scattered Aegean Archipelago islands being favored by rather appreciable wind and solar potential [1] encouraging the implementation of RES-based electrification solutions, are in great deal described by heavy oil and diesel electricity generation features that determine the former electricity supply status. More specifically, the increased fuel consumption leading to analogous electricity production costs and environmental pollution [2] along with the special characteristics attributed to such small autonomous electrical grids, i.e. serious barriers set to a respectable RES penetration [3], well demonstrate the situation existing in the specific area. Meanwhile, energy storage systems (ESS) are predominantly determined by their suitability in cases of significant energy demand variation in the course of time as well as in cases that the energy generation cannot be thoroughly controlled, e.g. in the wind energy production and the photovoltaic electricity generation. The phenomenon of a variable electricity load demand is more intense in small autonomous electrical networks, such as those encountered in thirty-six (36) of the Greek Aegean islands comprising autonomous electrical grids, Fig. 1. As already mentioned, the electricity generation cost in these specific islands is remarkably high [4], Fig. 2, therefore

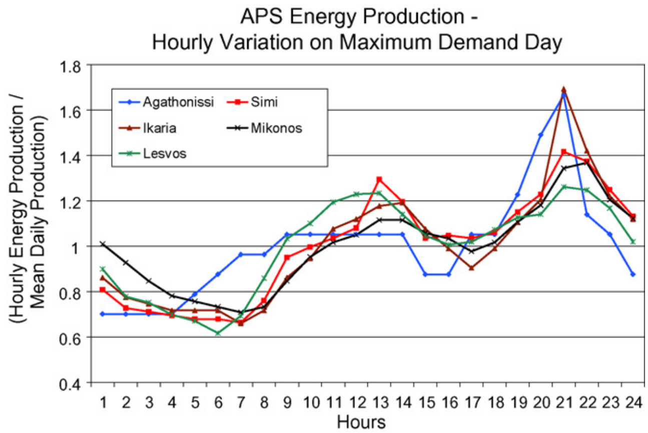

Fig. 1. Daily electricity consumption variation in representative Aegean Archipelago islands.

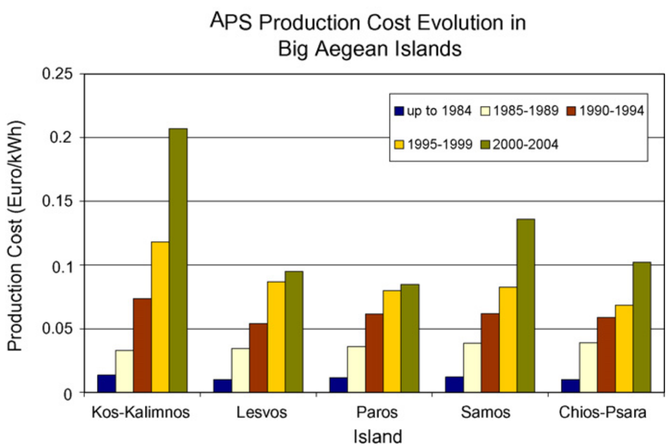

Fig. 2. Time-evolution of electricity production cost of selected big Aegean Archipelago islands.

allowing for a competitive advantage to appear in respect of the wind and solar energy exploitation.

As a matter of fact, if also considering the respectable wind and solar potential of the area, (Fig. 3) the installation of wind farms and photovoltaic power stations, both implying an appreciable energy yield, becomes techno-economically feasible. However, the instability of the existing electrical grids and the requirement for complete control over the quality of the electrical energy provision, set some serious obstacles in the dynamic exploitation of RES in autonomous electrical networks, this leading to the introduction of an upper limit of instantaneous RES contribution equal to a pre-described percentage (e.g. 30%) of the corresponding electricity demand. The specific constraints along with the intense seasonal electricity demand variation encountered in the islands have up to now resulted in a maximum 10% of RES annual participation in the local electrical energy balance [4], thus bounding further RES utilization and also insisting on the imported oil-dependent thermal power stations solution for the security of supply with significant macroeconomic and environmental costs entailed.

To confront the problem described, several authors have every so often proposed alternative supply concepts such as water-pumping solutions, hydrogen storage, battery schemes and hybrid systems [5–8]. In the present study, an effort is realized to systematically investigate the possibility of utilizing appropriate energy storage systems leading to both increased RES power stations presence and optimum operation of existing thermal power stations. As a result, reduced electricity generation costs and abundant high quality provision of electrical energy with minimum environmental impacts are to be expected.

In this context, an integrated methodology of techno-economical evaluation for the existing commercially-established and potentially applicable to the Greek islands electrical networks ESS is presented. Accordingly, the proposed methodology is applied to representative case studies in order for the results obtained to be compared with the already existing solutions.

2. Problem presentation-proposed solution

Currently, the electricity balance status is determined by the operation of oil-based thermal power stations – most of them being outmoded – and by minimum or even zero RES contribution, mostly deriving from wind farms. Considering the above, the increase of RES contribution, the installation of one or more energy storage systems, and the use of thermal power stations only as supplementary or back-up units, are strongly recommended (e.g. the island of Kythnos [9]). For this purpose, a demarcation between the islands featured by appreciable wind potential and the islands favored by respectable solar potential suggests the maximum possible exploitation of wind energy in the first case (and PV stations as the case may be) and the corresponding solar in the second, with the latter mainly encountered in the smaller-scale islands.

The proposed operation principle of a respective electrical scheme (Fig. 4) supports the prior exploitation of RES in collaboration with state of the art internal combustion engines set to operate in the range of minimum specific fuel consumption (maximum efficiency), while the ESS adopted is used to meet the satisfaction of power quality issues. In case of energy surplus, the excess amounts of energy are used to charge the ESS. When increased load demand and low RES production rates appear, the energy content of the ESS is used and if necessary, the programmed control of the thermal power stations calls for the back-up engines to set out.

The main points configuring the proposed solution are following:

- The extent of the thermal power units' utilization is principally dependent on the rated power of the existing RES stations and secondarily on the dynamics (capacity, input and output power) of the ESS employed.
- The existing thermal units being used for much less time leads to the extension of their service period and the reduction of maintenance needs, therefore prolonging the replacement requirements and constraining the environmental and macroeconomic effects.
- When asked to set out, the existing thermal power units should operate with regards to their operational character-

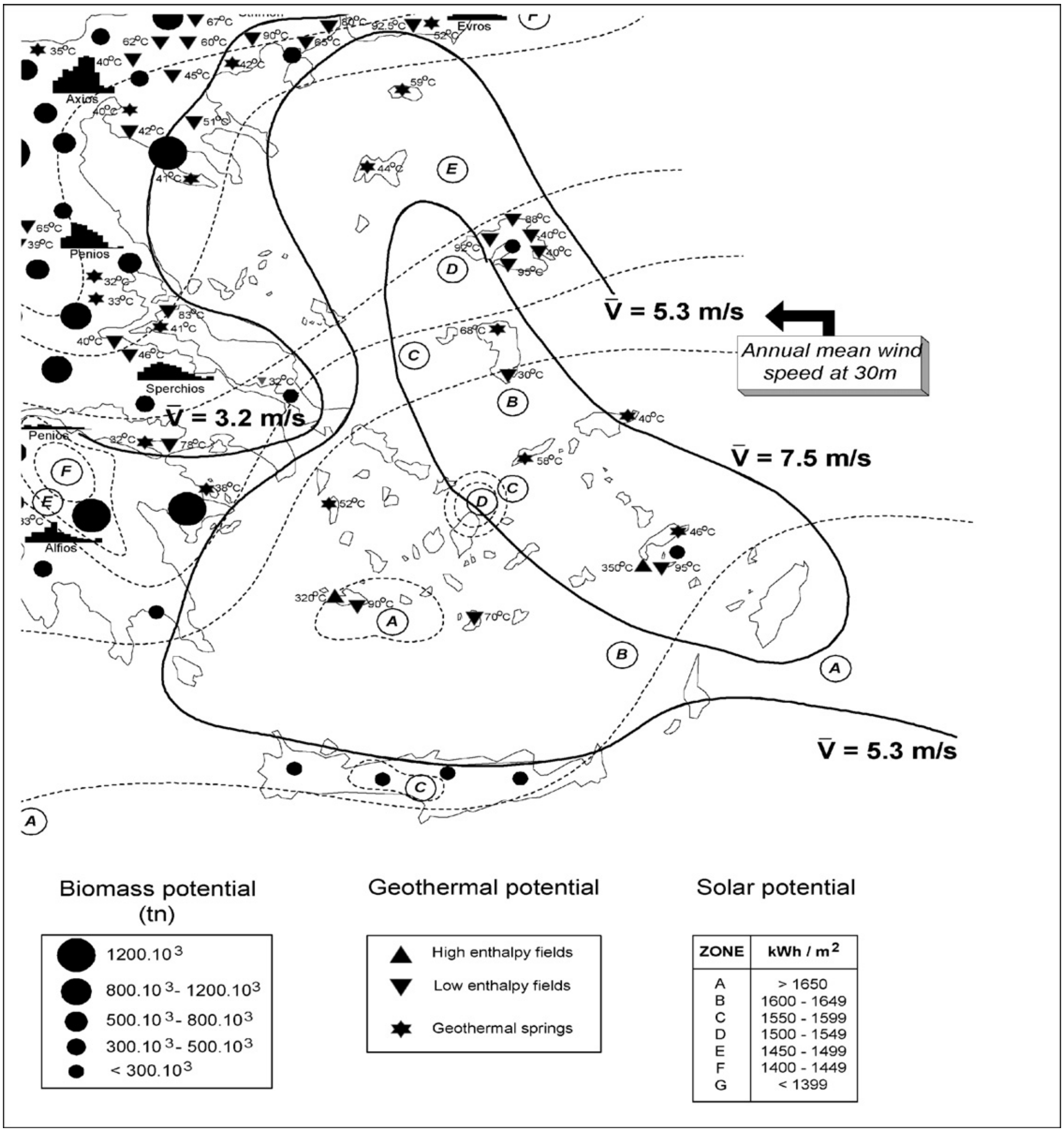

Fig. 3. RES potential in the Aegean Archipelago region.

istics and remain at all times close to the optimum point of operation (reduced cost and wear).

- The increased and prioritized contribution of RES combined with the respectable wind and solar potential of the area, further ameliorates the already (scale economies-no cut-outs) high economic efficiency of the specific technologies.
- The relatively high procurement cost of energy storage systems, thoroughly compensated if also considering the extremely high operational cost of the existing autonomous power stations (APS) (Fig. 2), eventually turns out to considerable pay offs and gains.

3. Analysis of existing situation-selection of ESS

From the analysis of recently published (2005) official energy consumption data (Fig. 5), it becomes clear that the operational area of existing APS ranges between 300 MWh and 300,000 MWh per year. Correspondingly, the peak load demand ranges from 100 kW to 100 MW. More explicitly, the existing electricity networks may be classified into four main groups based on the annual energy consumption and the corresponding peak load demand (see also Table 1).

- The first of the groups (Group I) includes 8 tiny islands with a population of less than 200 habitants, peak load demand up to 600 kW (in any case less than 1 MW) and annual energy production up to 2 GWh.
- The second group (Group II) comprises of 7 relatively small scale islands with an annual energy production up to 15 GWh (class of 10 GWh = 10×1 GWh) and peak load demand up to 5 MW (10 × 500 kW).
- The third group (Group III) includes 13 medium sized islands with an annual energy production up to 100 GWh (100 × 1 GWh) and a corresponding load demand up to 35 MW.
- Finally, the last group (Group IV) involves all the big scale islands of the Aegean Archipelagos (apart from Crete) with

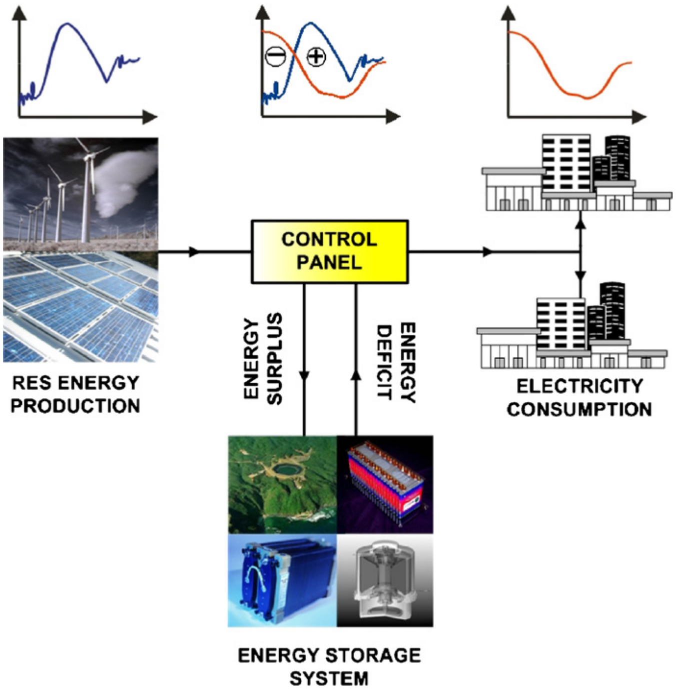

Fig. 4. Typical energy storage system configuration.

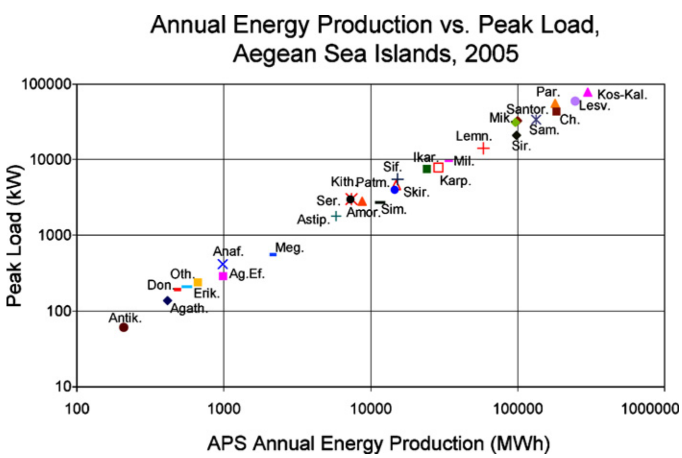

Fig. 5. Main operational characteristics of Greek islands APS (2005).

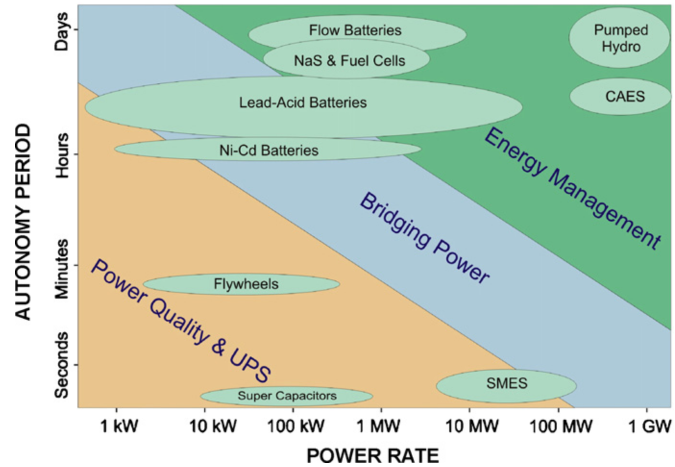

Fig. 6. Energy storage systems applications' range (based on material by ESA), presenting the autonomy period and the power covered by each specific energy storage system.

an installed electrical power over 40 MW and an energy production that exceeds 100 GWh per year.

Moreover, since the presence of thermal power stations should be considered as de facto even in the case of an increased RES contribution, a rationalized upper limit regarding the autonomy of the ESS is set equal to 24 h. Consequently, the requirements of an ESS may be determined by a maximum autonomy of 24 h (likely time periods of 6–12 h) and load demand from 0.1 MW to 100 MW maximum. Given the presence of the APS, the load demand share to be covered by the ESS should not lead to the purchase of a system greater than 10 MW rated power (maximum 20 MW), this irrationalizing the system's utilization.

In Fig. 6 one may encounter the application ranges of the currently established ESS, based on the available literature data. Regarding the area of interest (power demands from 100 kW to 20 MW and autonomy periods from 2 to 24 h) the proposed systems currently investigated are the following:

- lead-acid batteries (100 kW to 10 MW);
- Na–S batteries (100 kW to 10 MW);
- fuel cells (100 kW to 10 MW);
- flow batteries (100 kW to 10 MW);
- Li-ion batteries (100 kW to 1 MW);
- pumped hydro (1 MW to 100 MW);
- CAES (1 MW to 100 MW);
- flywheels (≈100 kW).

From the present energy analysis the systems of super capacitors (SC) and superconducting magnetic energy storage (SMES), both referring to power quality applications mostly [10,11], are excluded. Moreover, although efforts to face the serious environmental impacts caused by the use of Ni–Cd batteries (owed to the cadmium deposition) have been

Table 1
Aegean islands classification in terms of peak load demand [4]

Category (scale)	Peak load demand (MW)	Electricity production (GWh)	Islands
Very small	<1 MW	<2 GWh	Agathonissi, Agios Efstratios, Anafi, Antikithira, Donoussa, Erikousses, Megisti, Othoni
Small	<5 MW	<15 GWh	Amorgos, Astipalea, Kithnos, Samothrace, Serifos, Simi, Skiros
Medium	<35 MW	<100 GWh	Andros, Ikaria, Ios, Karpathos, Milos, Patmos, Andros, Lemnos, Mikonos, Santorini, Siros, Sifnos, Samos
Big	>40 MW	>100 GWh	Chios, Kos-Kalimnos, Lesvos, Paros, Rhodes

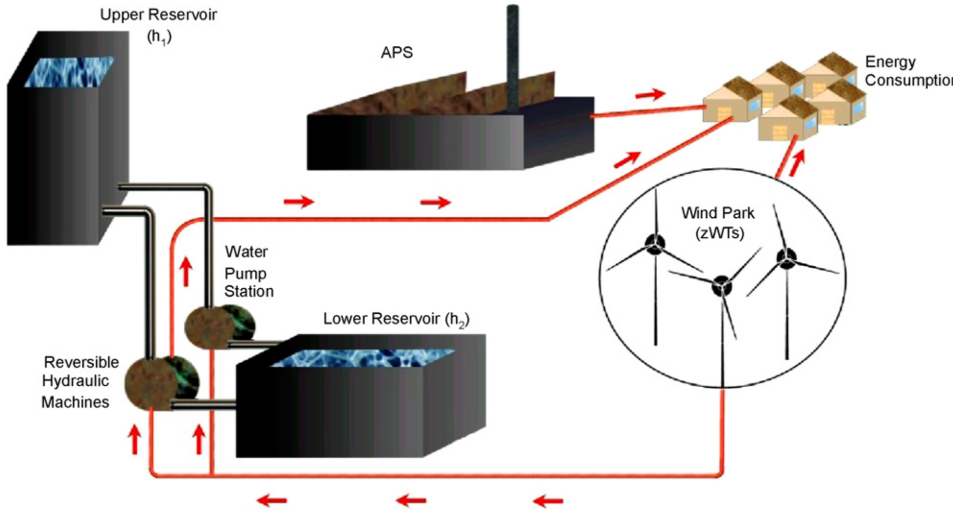

Fig. 7. Pumped hydro storage.

encountered [12], an established method is not yet developed, hence the latter will not be considered as well. Accordingly, the main features for each of the technologies examined are pointed out with emphasis laid on their application range.

4. Brief description of energy storage systems

As already mentioned, several ESS may be used to cover the electricity demand problems of numerous remote islands of Aegean Archipelago in collaboration with the existing APS and RES-based power stations (mainly wind parks and photovoltaic generators). For application purposes one should, for every ESS, define several operational parameters of every system, like the corresponding service period "n_{ss}", the maximum permitted depth of discharge "DOD_L" for long-term operation, the total (round-trip) energy efficiency "η_{ss}", the efficiency of the power output branch "η_p", the initial cost "IC_0", the annual maintenance and operation coefficient "m" and the power range in which every system can be utilized.

4.1. Pumped hydro storage (PHS)

In a pumped hydro storage system, the energy surplus appearing in times of low demand and increased production (e.g. from existing wind parks or PV stations) is exploited to pump water into an elevated (upper) storage reservoir, Fig. 7. Accordingly, during peak demand periods, water is released from the upper reservoir and the hydro turbines of the installation operate to "feed" the connected electrical generators. Thus, the system is able to cover the existing power deficit by using the appropriate amount of energy previously stored. Moreover, PHS systems are able of taking up load in a few seconds and are well defined by the high rates of extracted energy.

The typical overall efficiency of such systems mostly ranges between 65% and 77% [13], while their maximum depth of discharge is up to 95% without affecting their considerable (up to 50 years) service period. Since the lack of suitable sites is a fact, the main drawback for the creation of a new PHS system is the high capital cost, directly related to the need for the creation of two reservoirs with a respectable elevation difference. Towards this direction, open sea [14] along with underground caverns [15] may also serve as lower reservoirs as well. The environmental impact caused during the construction works and operation on the surroundings is also a matter of concern [16]. Finally, in terms of specific investment cost, a larger project seems more attractive [17], hence installations of rated power less than 1 MW (Island Group-I) will not be analyzed here.

4.2. Compressed air energy storage (CAES)

The CAES cycle is a variation of a standard gas turbine generation cycle. Hence, in a compressed air energy storage system, Fig. 8, off-peak or excess power from RES-based applications is used to pressurize air into an appropriate air storage facility (e.g. underground cavern) via a compressor. During times of peak demand, the required amount of air to cover the consumers' load is released from the cavern and supplied to a gas turbine where expansion takes place. Electricity is then generated from the directly connected electric generator. Before being expanded, the amount of preheated air (in the recuperator) is sufficiently heated in the combustion chamber of the installation, Fig. 8. CAES, like PHS, demands favorable sites and geological formations suitable for underground storage. The storage media most commonly used are rock caverns, depleted gas fields, saline aquifers and salt caverns [18,19].

The benefit arising from the operation of a CAES system lies on the fact that the stages of compression and generation are separated from one another. Consequently, what seems to be as much as 60–70% of fuel consumption for the compressor to be driven in a typical gas turbine generation cycle is not the case for a CAES cycle. In conclusion, in a CAES system, the entire power of the gas turbine is available to the consumption, however important fuel consumption is necessary. In fact, during a charging/discharging cycle, approximately one kWh

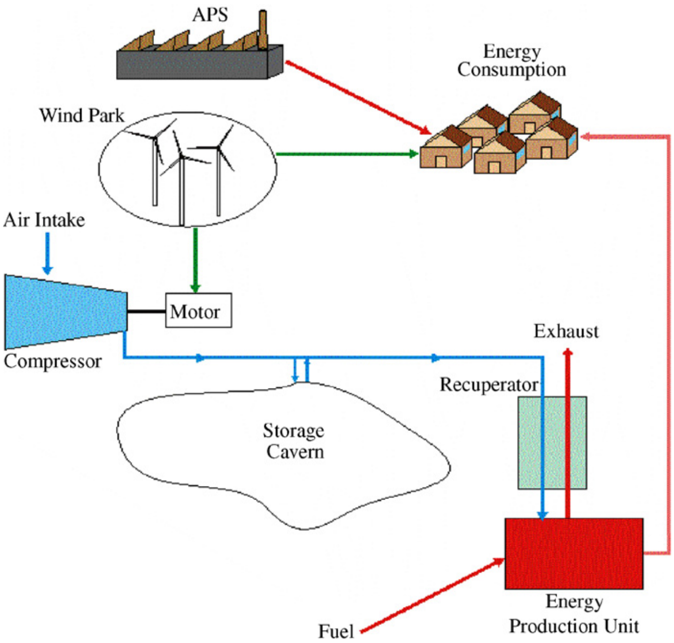

Fig. 8. Compressed air energy storage.

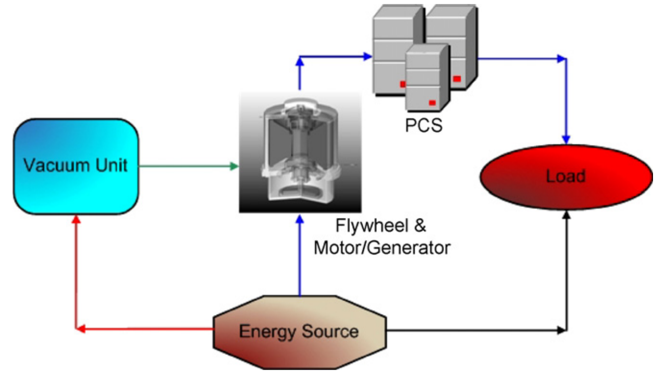

Fig. 9. Flywheel storage system.

of generated electricity requires about 0.75 kWh of compression energy and 4500 kJ of fuel [16]. This required amount of fuel is the main subject of controversy over the unconditional acceptance of such systems.

Due to the distinctive features given by the use of gas in a conventional CAES, the efficiency rate of the system can be expressed in different ways. Excluding the gas role and based only on the efficiency of expansion and compression, an overall electricity efficiency rate that can be directly compared to other storage technologies is around 70% [20]. It is important to consider that the viability of such systems is well dependent on the storage media. Assuming an already existing cavern is utilized, additional benefits concerning environmental impacts should also be appreciated [21]. In terms of capacity range, if taking into consideration that the rated power of the existing CAES installations are higher than 100 MW, CAES is thought to be the only, up to now, reliable alternative option for PHS. In this context, CAES are not thought as an appropriate solution for small scale applications like the ones corresponding to the Island Group-I of Table 1.

4.3. Flywheels energy storage (FES)

In a flywheel energy storage system [22,23], Fig. 9, kinetic energy is stored by causing a disk or rotor to spin on its axis. The amount of energy stored in a flywheel is directly proportional to the rotor's mass moment of inertia and the square of its rotational speed. When short-term back-up power is required the flywheel takes advantage of the rotor's inertia and the kinetic energy previously stored is converted into electricity. A modern flywheel consists of a rotating mass (a rim attached to a shaft) supported by bearings and connected to a motor/generator. During the motor operation, electrical energy is provided to the stator and the produced torque increases the kinetic energy of the rotor. During discharge, the system operates in the opposite way.

To minimize air drag and bearing losses, the flywheel along with the motor/generator must be placed inside a vacuum chamber so as to avoid deceleration effects caused by air. Concerning the friction losses, the bearings currently suggested to use for the latter minimization are the active magnetic, the passive magnetic, and the superconducting magnetic bearings [22,24].

Some of the key features describing the flywheels' nature [23] are the high power and energy density, the relatively low maintenance needs (consider that a flywheel consists of kinetic components), the rather short recharging time, the friendly characteristics towards environment, the deep discharges and the high overall efficiency value (~85%). The losses during standby operation are not higher than 2% of the flywheel's rated power. In any case, one cannot find flywheels applications for rated power higher than some hundreds of kW, while their potential operational period is kept within a maximum of few hours. For this reason flywheel system should be used only for the very small islands of Group-I.

4.4. Battery energy storage (BES)

Batteries are the most popular storage system. As far as their application range is concerned, battery energy storage systems show almost no restrictions. The technologies currently examined are the "mature" lead-acid along with the advanced sodium–sulphur and lithium-ion batteries, lately beginning to commercialize. In fact Li-ion systems may be used only for the very small islands of Group-I, i.e. maximum power rate less than 500 kW.

The components of a BES system (Fig. 10) are the string of batteries, the power conversion system and the control system. The factors that mostly affect the operation of a battery system are the depth of discharge, the temperature of operation, the number of cells in series, the discharge–charge control and the periodic maintenance. The main advantage of the technology is the absence of kinetic parts, implying the reduction of the operation and maintenance cost.

In brief, lead-acid batteries are defined as a mature technology with known performance characteristics and a reliable market background [25–27]. The low self-discharge

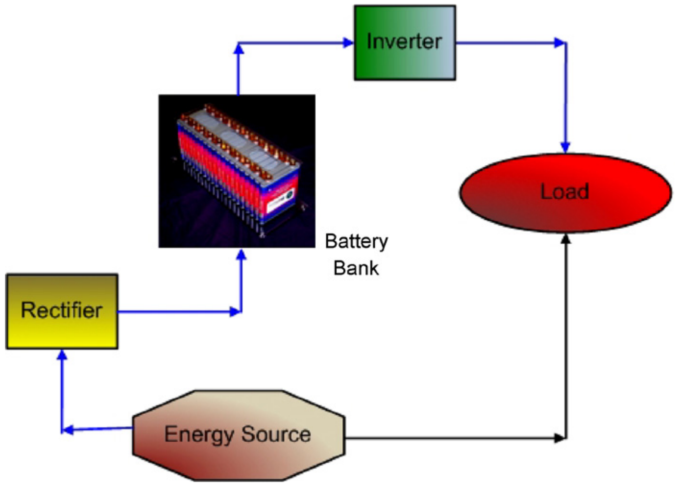

Fig. 10. Battery storage system.

value, the proven standby capability and the low maintenance requirements are some of the main advantages. On the other hand, the low energy density, the limited service period, the environmentally unfriendly content and the recommended low depth of discharge are the drawbacks of the particular technology [28].

Subsequently, Na–S batteries demonstrate increased energy densities, both gravimetric and volumetric in comparison with the lead-acid ones [28]. Due to the existence of beta alumina (it has zero electron conductivity) there is no self-discharge phenomenon. In addition, the energy efficiency of such batteries is kept quite high and may reach a value of 85%. At the same time the cost is thought to be low, the maintenance needs appear insignificant, and the service period is very satisfying. However, the use of Na–S may not be able to satisfy certain systems' requirements as the need to maintain the temperature high levels (320–360 °C) sets a serious obstacle.

Finally, the main advantages of lithium-ion technology are the high energy density with a potential for yet higher capacities, the high efficiency value (~95%), and the respectable lifetime combined with deep discharges [29]. Additional advantages include the low self-discharge rate, the low maintenance needed and the ability for the provision of very high currents [30]. The limitations set at present are the required protection circuits to maintain voltage and current within safety limits, the technology not yet sufficiently developed and the high cost for the batteries' manufacture.

4.5. Flow batteries (FB)

Flow batteries, also known as redox flow cells, constitute a relatively new technology. The energy is stored and released by means of a reversible chemical reaction. The charging and discharging stages introduce the conversion from electrical to chemical energy, and vice versa. The main characteristic of these systems is that the energy and power ratings are independent from one another. The storage capacity exclusively depends on the quantity of the electrolytes used, while the power rating is determined by the active area of the cell stack.

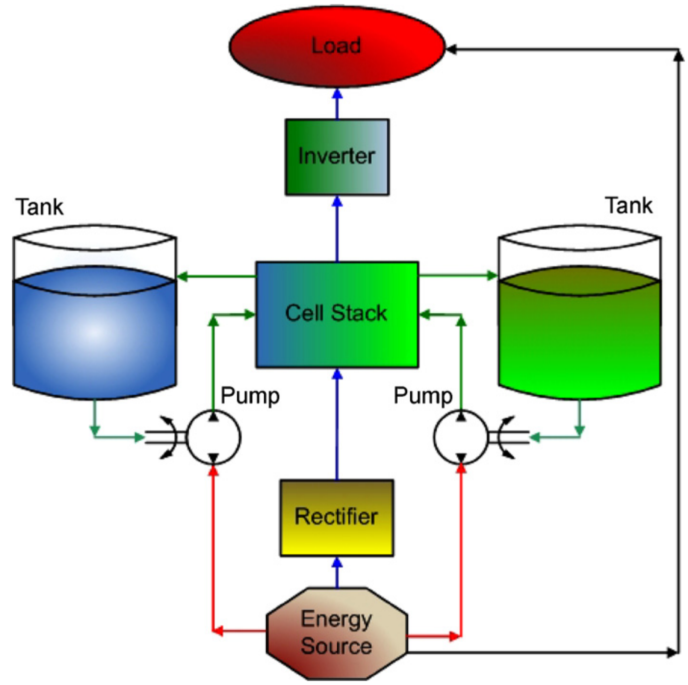

Fig. 11. Flow battery storage system.

The flow battery system, depicted in Fig. 11, is formed by a number of electrochemical cells, each one having two compartments (one for each electrolyte) being separated by an ion-exchange membrane. The two electrolytes are pumped from the tanks, through the cell stack and across a membrane. When passing through the membrane, the one electrolyte is oxidized and the other is reduced, producing current available to the external circuit. The employed pumps, necessary to circulate the electrolytes, bring some parasitic losses but at the same time contribute in keeping the system temperature at a desired level. An extra concern is the use of aggressive chemical solutions.

As already mentioned, the energy capacity of these systems depends on the size of the electrolytic tanks. Apparently, by increasing the quantities of electrolytes used, may lead to the service of large energy storage applications, in a scale where only PHS and CAES are occupied. The present technologies, presented in Table 2 [31], are principally defined by the electrolyte couples currently used.

Table 2
Capacity range of the three flow batteries technologies [31]

Technology	Representative systems	Projected capacity
Vanadium redox	250 kW,520 kWh 1.5 MW, 1.5 MWh	50 kW, 500 kWh to 5 MW, 20 MWh 50–100 MW upper range, 500 MW feasible
Na polysulphide/ Na bromide	12–15 MW, 120 MWh	5–50 MW, 100–250 MWh, 500 MW feasible
Zinc/bromine	50 kW, 500 kWh module 200 kW, 400 kWh trailer	300–600 kW, 300–1,000 kWh modular arrays 4–5 MW, 4–10 MWh upper range (no practical limit)

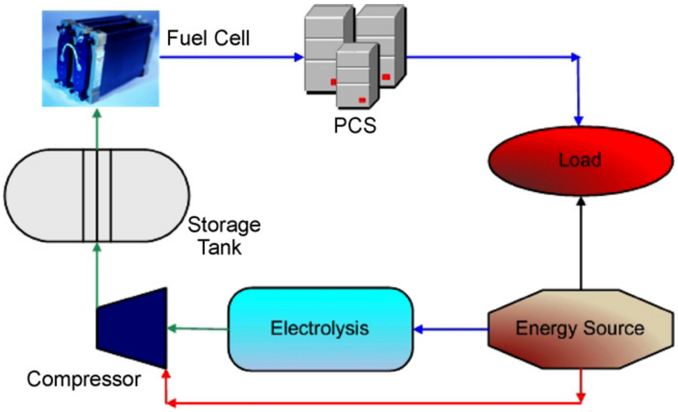

Fig. 12. Hydrogen storage system.

4.6. Fuel cells (FC)

Fuel cells consist (Fig. 12) of two electrodes surrounding an electrolyte. Oxygen passes over one electrode and hydrogen over the other, generating electricity, water and heat. In principle, a fuel cell operates like a battery. However, a fuel cell does not require recharging; as long as fuel is supplied to the cell, electricity is produced. Thus, the restrictions opposed on the storage capacity are only determined by the fuel tank size. The energy that a fuel cell produces is directly depended on the fuel cell type, the operation temperature, and the catalyst used to improve the chemical reaction's performance. There are several types of fuel cells that are commonly used. The main disadvantage of this technology is the overall efficiency rate, which by including the hydrogen storage procedure is estimated to be around 30–40%. The losses are detected during the electrolysis for the hydrogen to be produced, during the phase of storage, and finally during the generation procedure via the fuel cell.

The different types of fuel cells are able of covering a broad range of applications [32]. For example, for stationary applications where higher power demand along with high efficiency values are required the most suitable types are the MCFC and the SOFC. Additional beneficial characteristics of hydrogen-based storage systems are the high energy density of hydrogen (33 kWh/kg) and the well separated stages of storage and production.

5. Energy storage system sizing

The problem to be solved concerns an autonomous electrical network, which for a given time period (e.g. 1 year) presents total electricity consumption "E_{tot}", peak load demand equal to "N_p", while the rated power of the existing power stations is "N_0". For safety reasons:

$$N_0 \geq N_p \tag{1}$$

or introducing an appropriate safety factor "SF" one may write

$$N_0 = N_p(1+\mathrm{SF}) \tag{2}$$

In this context the capacity factor "CF" of the autonomous electrical system is defined as

$$\mathrm{CF} = \frac{E_{tot}}{8760 N_0} = \frac{E_{tot}}{8760 N_p(1+\mathrm{SF})} = \frac{E_h}{N_p(1+\mathrm{SF})} \tag{3}$$

where

$$E_h = \frac{E_{tot}}{8760} \tag{4}$$

is the average hourly load of the electrical network under investigation.

During the present analysis we assume that the total energy demand is covered either directly by the existing power stations "E_{dir}" (thermal power stations, wind parks, photovoltaic generators, etc.) or via the energy storage system "E_{stor}". In order to describe the contribution of the storage system to the total energy consumption we define the parameter "ε" as

$$\varepsilon = \frac{E_{stor}}{E_{tot}} = 1 - \frac{E_{dir}}{E_{tot}} \tag{5}$$

since

$$E_{tot} = E_{dir} + E_{stor} \tag{6}$$

As it is obvious, theoretically "ε" takes values between zero (no storage system usage) and one (all the energy consumption is covered through the storage system), i.e. $0 \leq \varepsilon \leq 1.0$. In practice, between these two extreme values, a contribution range determined by the existing power units' principle features (including photovoltaics and wind turbines) dictates the potential use of the ESS on an annual basis.

In any case the ESS under evaluation is characterized by the energy storage capacity "E_{ss}", the maximum input power "N_{in}" and the nominal output power "N_{ss}" of the entire energy storage subsystem. More precisely, the energy storage capacity may be estimated by the following relation:

$$E_{ss} = d_0\left(\frac{E_{stor}}{8760}\right)\frac{1}{\eta_{ss}}\frac{1}{\mathrm{DOD_L}} = \varepsilon(d_0 E_h)\frac{1}{\eta_{ss}}\frac{1}{\mathrm{DOD_L}} \tag{7}$$

where one should take into account the desired hours of energy autonomy "d_0", the maximum depth of discharge "$\mathrm{DOD_L}$" and the energy transformation (round-trip) efficiency of the ESS "η_{ss}".

In regard to the nominal output power "N_{ss}" of the storage unit, it is the power efficiency "η_p" that must be considered as well, i.e.:

$$N_{ss} = \zeta\frac{N_p}{\eta_p} = \zeta\frac{E_h}{\mathrm{CF}}\frac{1}{\eta_p}\frac{1}{1+\mathrm{SF}} \tag{8}$$

where "ζ" is the peak power percentage of the local network that the energy storage branch should cover, see also Eq. (3).

Accordingly, the input power "N_{in}" of the ESS depends on the available power excess of the existing electricity generation units and the desired charge time "Δt_{ch}" of the installation, since the following relation may be used as a first estimation:

$$\Delta t_{ch} \approx \frac{E_{ss}}{N_{in}} \tag{9}$$

Finally, the utilization (or capacity) factor "CF_{ss}" of the ESS is given as

$$CF_{ss} = \frac{E_{stor}}{8760N_{ss}} = \frac{\varepsilon E_{tot}}{8760N_{ss}} = \frac{\varepsilon}{\zeta} CF\eta_p(1+SF) \tag{10}$$

6. Electricity generation cost

The total investment cost (after -n years of operation) of an energy storage installation [33,34] is a combination of the initial installation cost and the corresponding maintenance and operation cost, both quantities expressed in present values. In this context, the initial cost "IC_{ss}" of an ESS can be expressed as a function of two coefficients. The first "c_e" (€/kWh) related to the storage capacity and the type of the system, and the second "c_p" (€/kW) referring to the power conversion system's nominal power (i.e. inverter, hydro-turbine, gas–turbine, etc.) and the type of the storage system. In this analysis one implicitly assumes that the input power of the system is of the same order to the corresponding output power of the ESS (or the charge and discharge time periods are comparable), hence one may use the following relation:

$$IC_{ss} = c_e E_{ss} + c_p N_{ss} = E_h\left[\frac{c_e d_0 \varepsilon}{\eta_{ss} DOD_L} + \frac{c_p \zeta}{CF\eta_p}\frac{1}{1+SF}\right] \tag{11}$$

In order to obtain a first idea of the numerical values of the above mentioned parameters (i.e. DOD_L, η_{ss}, η_p, c_e, c_p) one may use the data of Table 3, based on the available information in the international literature [35–38]. In the same Table 3, the service period "n_{ss}" and the corresponding annual M&O factor "m" are also included. As it is obvious from Table 3, a wide range of values have been found for most energy storage systems under investigation.

Subsequently, in addition to the initial investment cost one should also take into consideration the input energy cost "EC", i.e. the cost of energy supplied to the storage system in order to be able to provide the amount of energy expected (εE_{total}). Since the amount of energy needed to charge the storage system is expressed as ($\varepsilon E_{total}/\eta_{ss}$), the corresponding input energy cost for a time period of "n" years (in present values) can be expressed as

$$\begin{aligned} EC_{ss} &= \frac{E_{stor}}{\eta_{ss}} c_1 \sum_{j=1}^{j=n}\left(\frac{(1+x_1)}{(1+i)}\right)^j \\ &= \varepsilon\frac{E_{total}}{\eta_{ss}} c_1 \sum_{j=1}^{j=n}\left(\frac{(1+x_1)}{(1+i)}\right)^j = \varepsilon\frac{E_{total}}{\eta_{ss}} c_1 X_1 \end{aligned} \tag{12}$$

where "c_1" is the specific input energy cost value and "x_1" is the mean annual escalation rate of the input energy price, while "i" is the capital cost of the local market.

Accordingly, the M&O cost can be split into the fixed maintenance cost "FC_{ss}" and the variable one "VC_{ss}". Expressing the annual fixed M&O cost as a fraction "m" (see Table 3) of the initial capital invested and assuming an annual increase of this cost equal to "x_2", the present value of "FC_{ss}" is given as

$$FC_{ss} = IC_{ss} m \sum_{j=1}^{j=n}\left(\frac{1+x_2}{1+i}\right)^j = IC_{ss} m X_2 \tag{13}$$

The distinctive nature of a CAES principle operation imposes the need for the fuel factor to be also included [39]. In fact, a typical CAES requires a considerable fuel input in the combustion chamber of the installation [40], see also Section 4.2. In this context, equation (13) is rewritten in order to include the fuel input contribution as following

$$\begin{aligned} FC_{ss} &= IC_{ss} m \sum_{j=1}^{j=n}\left(\frac{1+x_2}{1+i}\right)^j + c_f(E_{stor})\sum_{j=1}^{j=n}\left(\frac{1+x_3}{1+i}\right)^j \\ &= IC_{ss} m X_2 + c_f(\varepsilon E_{total}) X_3 \end{aligned} \tag{14}$$

The "c_f" coefficient derives by combining the specific energy cost of the fuel used with the amount of fuel needed per kWh produced via the gas turbine incorporated (e.g. 4500 kJ/kWh). Besides, "x_3" expresses the mean annual escalation rate of fuel input price in case of CAES.

The variable maintenance and operation cost mainly depends on the replacement of "k_0" major parts of the installation, which have a shorter lifetime "n_k" than the complete installation "n_{ss}". Using the symbol "r_k" for the replacement cost coefficient of each one of the "k_0" major parts of the installation, the "VC_{ss}" term can be expressed as

$$VC_{ss} = IC_{ss} \sum_{k=1}^{k=k_0} r_k \left\{ \sum_{l=0}^{l=l_k} \left(\frac{(1+g_k)(1-\rho_k)}{(1+i)}\right)^{l n_k} \right\} = IC_{ss} vc_{ss} \tag{15}$$

with "l_k" being the integer part of the following equation (16), i.e.

$$l_k = \left[\frac{n-1}{n_k}\right] \tag{16}$$

while "g_k" and "ρ_k" describe the mean annual change of the price and the corresponding level of technological improvements for the "k-th" major component of the energy storage installation.

Recapitulating, the total cost ascribed to the storage system installation and operation after "n" years (in present values) may be estimated using Eq. (17).

$$\begin{aligned} C_{ss} &= IC_{ss}(1-\gamma) + EC_{ss} + FC_{ss} + VC_{ss} \\ &\Rightarrow C_{ss} = IC_{ss}\{(1-\gamma) + mX_2 + vc_{ss}\} \\ &+ (\varepsilon E_{total})\left\{\frac{c_1}{\eta_{ss}} X_1 + c_f X_3\right\} - \frac{Y_n}{(1+i)^n} \end{aligned} \tag{17}$$

where "γ" is the subsidy percentage by the Greek State and "Y_n" is the residual value of the ESS after n-years of operation in current values. For simplicity reasons one may define as

Table 3
Major characteristics of the energy storage systems examined [35–38]

Storage system	Service period n_{ss} (years)	DoD (%)	Power efficiency η_p (%)	Energy efficiency η_{ss} (%)	Specific energy cost c_e (€/kWh)	Specific power cost c_p (€/kW)	M&O m (%)
P.H.S.	30 ÷ 50	95	85	65 ÷ 75	10 ÷ 20	500 ÷ 1500	0.25 ÷ 0.5
C.A.E.S.	20 ÷ 40	55 ÷ 70	80 ÷ 85	70 ÷ 80	3 ÷ 5	300 ÷ 600	0.3 ÷ 1
Regenesys	10 ÷ 15	100	75 ÷ 85	60 ÷ 70	125 ÷ 150	250 ÷ 300	0.7 ÷ 1.3
F.C.	10 ÷ 20	90	40 ÷ 70	35 ÷ 45	2 ÷ 15	300 ÷ 1000	0.5 ÷ 1
Lead Acid	5 ÷ 8	60 ÷ 70	85	75 ÷ 80	210 ÷ 270	140 ÷ 200	0.5 ÷ 1
Na–S	10 ÷ 15	60 ÷ 80	86 ÷ 90	75 ÷ 85	210 ÷ 250	125 ÷ 150	0.5 ÷ 1

"$\tilde{\upsilon}_n$" the non-dimensional value of "Y_n" in present values, i.e.:

$$\tilde{\upsilon}_n = \frac{Y_n/\mathrm{IC_{ss}}}{(1+i)^n} \tag{18}$$

Finally, one may express the present value of the electricity generation cost (€/kWh) of the ESS by dividing the total cost of the installation during the n-year service period with the total energy generation during the same period, taking into consideration the expected produced electricity price escalation rate "x_4". Therefore the corresponding electricity generation cost is given as

$$c_0 = \frac{C_{ss}}{\mathrm{E_{stor}}\sum_{j=1}^{j=n}\left((1+x_4)/(1+i)\right)^j} = \frac{C_{ss}}{\varepsilon E_{tot} X_4} \tag{19}$$

Substituting Eqs. (12), (14), (15), (17) and (18) into Eq. (19) we get that

$$c_0 = \frac{\mathrm{IC_{ss}}}{\varepsilon E_{tot}}\left(\frac{1-\gamma}{X_4} + m\frac{X_2}{X_4} + \frac{\mathrm{vc_{ss}}}{X_4} - \frac{\tilde{\upsilon}_n}{X_4}\right) + \frac{c_1}{\eta_{ss}}\frac{X_1}{X_4} + c_f\frac{X_3}{X_4} \tag{20}$$

Using Eqs. (4) and (11) one may estimate the ratio "$\mathrm{IC_{ss}}/(\varepsilon E_{tot})$" as follows

$$\frac{\mathrm{IC_{ss}}}{\varepsilon E_{tot}} = \frac{1}{8760}\left[\frac{c_e d_0}{\eta_{ss}\mathrm{DOD_L}} + \frac{c_p}{\mathrm{CF}\eta_p}\frac{\zeta}{\varepsilon}\frac{1}{1+\mathrm{SF}}\right] \tag{21}$$

At this point it is important to define the terms "X_i" appearing in the above equations. Note that all these parameters are depending exclusively on the corresponding economic parameters of the local market, thus one may write

$$X_i = \sum_{j=1}^{j=n}\left(\frac{1+x_i}{1+i}\right)^j \quad i = 1, 4 \tag{22}$$

Recapitulating, one may state that an energy storage investment is financially attractive if the energy production cost value of Eq. (20) is less than the energy production cost of the existing autonomous (thermal) power stations, see for example Fig. 2. Furthermore, one should also take into consideration the additional benefits related to the energy storage system operation, due to the increased reliability of the entire electrical network and the improved quality of the electricity offered.

7. Application results

The above mentioned analysis is going to be applied to representative autonomous island networks existing in the Aegean Archipelago, Fig. 3. In order to facilitate the in depth analysis of the electricity generation opportunities for the available ESS, as already mentioned, one may divide the existing power stations in four subgroups on the basis of their peak load demand, see also Table 1. More precisely, the first group includes very small islands, with rated power less than 1 MW. In this category one may find the tiny islands of Agios Efstratios, Donoussa, Megisti, etc. On the other hand, the last group includes the existing big APS, with rated power higher than 40 MW, like the ones of Rhodes, Lesvos, Kos-Kalimnos, etc.

Accordingly, one should also define representative long-term average values concerning the parameters "x_i" and "i" for the local market. More precisely, the capital cost "i" depends mainly on the investment opportunities, the timing of repayment and the risk of the investment. Subsequently, the term "electricity price escalation rate", describing the terms "x_1" and "x_4" takes into consideration the annual rate of change of the input and the produced electricity, respectively. In general, the exact value of these parameters depends on various factors (e.g. euro-dollar exchange rate, nature of the conventional energy to be replaced, the policy of the electrical utilities towards RES-ESS configurations). Next, the M&O cost inflation rate "x_2" describes the annual change (increase) of the M&O cost, taking into account the annual changes of labor cost and the corresponding spare parts. Finally, the term "x_3" expresses the mean annual escalation rate of fuel input price and is valid only for CAES. In fact, taking into consideration the long-term records and the expected prospects of the local market [33] we assume that $x_1 = x_4 = 3\%$, $x_2 = 3\%$, $x_3 = 5\%$ and $i = 8\%$.

7.1. Very small electrical networks

As mentioned above the first group examined consists of eight very small islands, which can be represented by a typical electrical network with average annual electricity consumption equal to 900 MWh, and corresponding peak load demand equal to 300 kW. Note that the current electricity production cost on the basis of the existing small thermal power stations is almost

0.65€/kWh with an average annual increase rate of over 10%. Using Eq. (4) the average hourly load of these islands is approximately 100 kWh/h, hence for every hour of energy autonomy provided by the ESS the energy amount required is equal to (100ε) kWh. In Fig. 1 one may see the typical hourly load demand of several islands, on annual basis.

Due to the small size of the islands examined some ESS may not be appropriate, e.g. PHS, CAES, to be adopted in similar situations. On the other hand, ESS used mainly for power quality purposes or for short term applications like flywheels and Li-ion batteries have been included mainly for comparison purposes. Assuming 50% annual contribution of the ESS ($\varepsilon = 50\%$), 12 h of energy autonomy of the system ($d_0 = 12$ h) and $\zeta = 1.0$ the electricity generation cost of the system ($c_1 = 0.1$€/kWh) is less than 0.22€/kWh, excluding the fuel cells solution, Fig. 13. In fact, for several ESS systems the life cycle (LC) cost is less than 0.20€/kWh, in comparison to the current electricity generation cost of 0.65€/kWh. According to the calculation results Na–S batteries and the Flywheel option present the minimum LC cost, i.e. 0.175€/kWh, while even the lead-acid batteries utilization shows an acceptable value of 0.222€/kWh. By doubling the desired energy autonomy of the system (i.e. $d_0 = 24$ h) a remarkable production cost increase is encountered, hence the minimum LC value (0.215€/kWh) is achieved by the utilization of either Na–S batteries or flow batteries (Regenesys). All the other ESS present a significant cost increase, while the flywheels cannot technically support such high energy autonomy values.

Besides the relative electricity production cost values are remarkably decreased (Fig. 14) as the ESS participation increases from 20% to 60%. The faster cost reduction is observed for the fuel cells, while the Na–S system shows that it is slightly affected by the "ε" increase. As it is easy to understand values of "ε" higher than 60% are not realistic and are included here only for theoretical comparison purposes.

7.2. Small electrical networks

The second group includes another seven islands with average annual electricity consumption of approximately 10,000 MWh and peak load demand equal to 3300 kW. The corresponding current electricity production cost is 0.27€/kWh with an annual average increase rate of 8%. Most islands possess high wind potential and abundant solar irradiance, hence one may encourage the RES exploitation in order to cover the local societies electricity demand. At this point one should mention that the average hourly load of the islands under investigation is approximately 1.2 MWh/h, thus for every hour of energy autonomy the corresponding ESS should provide (1200ε) kWh. In Fig. 1 the annual mean typical hourly load demand is depicted. According to the official data there are two peak load demand values, one during noontime and the other at night.

Due to the size of the islands examined some ESS – previously used – may not be appropriate, e.g. Li-ion batteries and Flywheels, while other systems like PHS and CAES may be applied in similar situations. Assuming 50% annual contribution of the ESS ($\varepsilon = 50\%$), 12 h of energy autonomy of the system ($d_0 = 12$ h) and $\zeta = 1.0$ the energy production cost of the system ($c_1 = 0.1$€/kWh) is less than 0.19€/kWh, excluding the lead-acid and fuel cells solutions, Fig. 15.

In fact, the minimum life cycle electricity generation cost is expected for PHS (i.e. 0.167€/kWh). In islands where this solution is not possible due to topographical restrictions the Na–S batteries and the Flow Batteries (Regeneys) option present also a low cost alternative, i.e. 0.172€/kWh and 0.189€/kWh respectively. By doubling the desired energy autonomy of the system (i.e. $d_0 = 24$ h) a remarkable production cost increase is encountered, for most ESS, excluding PHS and CAES. In this scenario the minimum LC

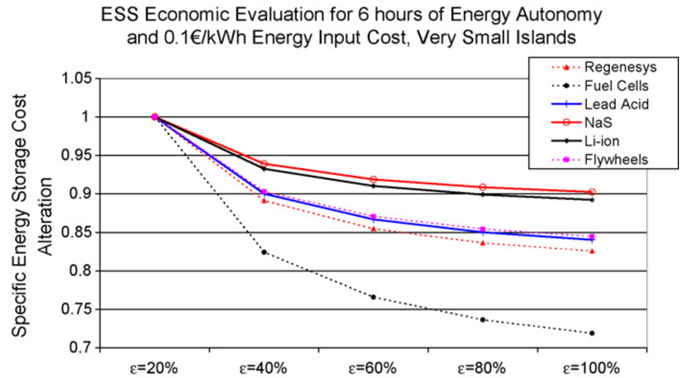

Fig. 14. Relative electricity production cost variation for very small islands.

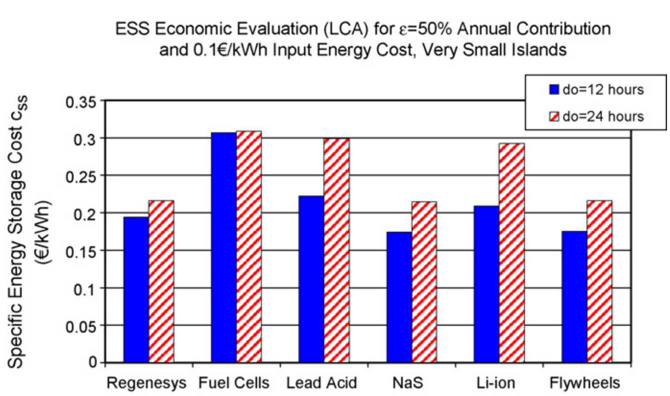

Fig. 13. Electricity production cost for very small islands.

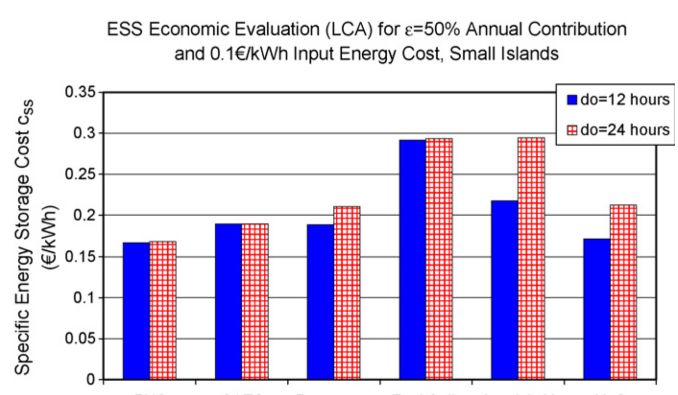

Fig. 15. Electricity production cost for small islands.

value (0.168€/kWh) is achieved by the PHS, while the second alternative should be based on CAES (0.190€/kWh). Note that the CAES cost is strongly influenced by the input fuel cost, hence any change in this value ($c_f = 0.034$€/kWh) is going to affect the calculated electricity cost value. Finally, one should underline the fact that the energy production cost value on the basis of ESS is quite lower than the marginal production cost of the existing thermal power stations.

7.3. Medium size electrical networks

The third island group contains another thirteen medium size islands with average annual consumption of 50,000 MWh and peak load demand equal to 10 MW. The corresponding current electricity production cost is 0.195€/kWh with an annual average increase rate of 6%. Due to their geographical location most islands possess high wind potential (wind parks exist in all these islands) and abundant solar irradiance. In this context, the average hourly load of the islands under investigation is approximately 6.0 MWh/h, thus for every hour of energy autonomy the corresponding ESS should provide (6000ε) kWh.

Assuming 50% annual contribution of the ESS ($\varepsilon = 50\%$), 12 h of energy autonomy of the system ($d_0 = 12$ h) and $\zeta = 1.0$ the energy production cost of the system ($c_1 = 0.1$€/kWh) is less than 0.19€/kWh, excluding the lead-acid and fuel cells solution, Fig. 16.

In fact, the minimum life cycle electricity generation cost is expected for PHS (i.e. 0.162€/kWh). In islands where this solution is not possible due to topographical restrictions the Na–S batteries, CAES and the Flow Batteries (Regeneys) option present also a low cost alternative, i.e. 0.170€/kWh, 0.187€/kWh and 0.186€/kWh respectively. By doubling the desired energy autonomy period of the system (i.e. $d_0 = 24$ h) a remarkable production cost increase is encountered, for most ESS, excluding PHS and CAES. In this scenario the minimum LC value (0.163€/kWh) is achieved by the PHS, while the second alternative should be based on CAES (0.187€/kWh). Note that CAES and PHS seem almost unaffected by the energy autonomy increase of the system, while the ESS based on any type of batteries is significantly increased. Fuel cells also are not influenced by the energy autonomy increase of the local network, however their electricity generation cost remains high at present.

7.4. Big island electrical networks

The last case analyzed concerns the five biggest islands of Aegean Archipelago with annual electricity consumption of approximately 200,000 MWh and peak load demand in the proximity of 50 MW. The corresponding current electricity production cost is approximately 0.10€/kWh with an annual average increase rate of 5%. Due to their size all the islands possess locations with high wind speed (wind parks exist in all these islands), while the corresponding solar irradiance is also considerable. In this context, the average hourly load of the islands under investigation is approximately 22.0 MWh/h, thus for every hour of energy autonomy the corresponding ESS should provide (22,000·ε) kWh. In this context, ESS based on batteries may not be technically feasible, however the corresponding calculation results are included here for theoretical comparison purposes.

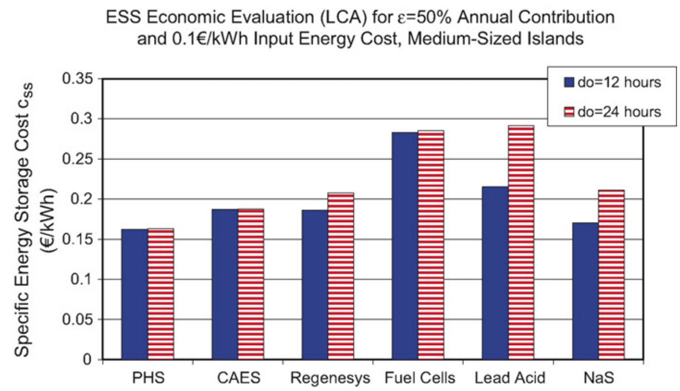

Fig. 16. Electricity production cost for medium-sized islands.

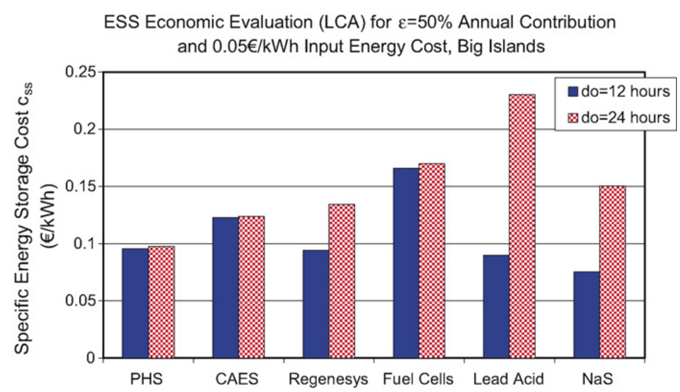

Fig. 17. Electricity production cost for big islands.

Assuming 40% annual contribution for the ESS ($\varepsilon = 40\%$), 12 h of energy autonomy for the system ($d_0 = 12$ h) and $\zeta = 1.0$ the energy production cost of the system ($c_1 = 0.05$€/kWh) is less than 0.10€/kWh, excluding the CAES and fuel cells solution, Fig. 17. In fact, the minimum life cycle electricity generation cost is expected for Flow Batteries and PHS (i.e. 0.095€/kWh). Both Na–S and lead-acid batteries present lower cost values, however one has not used similar systems for so large applications.

By doubling the desired energy autonomy of the system (i.e. $d_0 = 24$ h) a remarkable production cost increase is encountered, for most ESS, excluding PHS and CAES. In this scenario the minimum LC value (0.098€/kWh) is achieved by the PHS, while the second alternative should be based on CAES (0.124€/kWh). All other systems present electricity generation values definitely higher than the marginal production cost of the existing thermal power stations. As already mentioned the CAES production cost value strongly depends on the fuel cost value.

8. Conclusions

In the present study, an integrated methodology developed is able to estimate the electricity generation cost ascribed to the

implementation of various RES-ESS configurations on the basis of minimum energy dependence on local thermal power stations. For this purpose, one should take into account the corresponding schemes' sizing parameters as well as the electricity features of the network each time examined. In order to designate optimum combinations between the electricity network magnitude and the energy storage technologies, the proposed methodology is applied to four Aegean island-groups resulting from the variation in the rates of peak load demand and electricity consumption.

From the results obtained, it becomes evident that for the majority of RES-ESS configurations the resulting electricity generation cost is lower than the corresponding of the local APS, especially in the case of small and very small size islands. More specifically, it is the Na–S batteries that may be thought as suitable for very small island cases, while PHS comprise the optimum solution for big size islands. Lead acid batteries' mature technology may also be considered as an option for big scale islands, however suitable only for moderate autonomy periods.

Regarding the small and medium sized islands PHS appear to be slightly better than Na–S batteries for a given autonomy period of 12 h, while they present a clear advantage in the case of 24 h. Concerning CAES -largely dependent on the fuel cost factor- the specific system's adoption may be thought as an alternative only in medium and big scale islands and for large autonomy periods required.

Finally, fuel cells and flow batteries, positively influenced by the increased ESS participation in the local island network, may suggest promising future solutions since the corresponding technologies' costs are up to now higher than of other, more traditional systems investigated.

From the analysis undertaken it results that the proposed RES-ESS configuration comprises a financially viable electrification solution, also contributing to the production of reliable and high quality electricity. Hence, one may conclude that the prospect of further RES exploitation in the local island networks by using appropriate ESS along with the parallel reduction of the electricity generation cost and the abatement of environmental impacts is a realizable scenario, not jeopardizing the quality of energy provided.

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